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June 7, 2006

VIA ELECTRONIC FILING

Honorable Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1-A
Washington, D.C. 20426

Re: Arkansas Public Service Commission v. Entergy Corporation, et al.
Docket No. EL06-

Dear Ms. Salas:

Enclosed for filing in the above-referenced docket please find an electronic copy of Notice and the Complaint of the Arkansas Public Service Commission.

Thank you for your assistance in this matter.

Sincerely,

Mary W. Cochran
Mary W. Cochran
General Counsel

cc: Service List (U.S. mail)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Arkansas Public Service Commission	)	Docket No. EL06-__________
	)	
Versus	)	
	)	
Entergy Services, Inc.	)	
Entergy Louisiana, L.L.C.	)	
Entergy Arkansas, Inc.	)	
Entergy Mississippi, Inc.	)	
Entergy New Orleans, Inc.	)	

COMPLAINT OF THE
ARKANSAS PUBLIC SERVICE COMMISSION

Executive Summary

The Arkansas Public Service Commission files this Complaint against Entergy Services, Inc. and the Entergy Operating Companies pursuant to Sections 205, 206, and 207 of the Federal Power Act. The purpose of the Complaint is to institute an investigation into the prudence of Entergy's practices affecting the wholesale rates that flow through its System Agreement. The Arkansas Commission also requests that this Commission exercise its authority under FPA Section 207 to investigate the adequacy of Entergy's transmission system and direct it to make all necessary upgrades to ensure that its transmission facilities provide reliable, adequate, and economic service. The Complaint was necessitated by the Commission's Opinion Nos. 480 and 480-A, in which the Commission ruled that the production costs of the Operating Companies must be within +/-11% of the System average production cost. As a result of those opinions, lower-cost jurisdictions, such as Arkansas, have little ability to reduce production costs to retail customers because the benefits of such reductions would flow primarily to higher-cost jurisdictions in the form of higher payments. Similarly, higher-cost jurisdictions have little incentive to reduce production costs, because such reductions will result in lower revenues from the lower-cost jurisdictions.

The Arkansas Commission does not by this Complaint seek any change to Opinion Nos. 480 and 480-A, but will continue to pursue its appeal of those decisions. The Arkansas Commission in this docket seeks to reduce the Entergy system's *overall* production costs, because such a reduction is the Arkansas Commission's only means of reducing production costs to Entergy customers in Arkansas. The Commission should not wait until those appeals have been resolved before acting on this Complaint because costs being incurred now will form the basis for payments in 2007, if Opinion Nos. 480 and 480-A are affirmed. Moreover, many of the issues identified in this Complaint, such as wholesale purchasing practices and transmission expansion, affect wholesale markets in the Entergy region and should be addressed even if those opinions are reversed.

The Arkansas Commission requests that the Commission review the prudence of a broad array of Entergy's practices and disallow any costs found to be imprudent. Specific areas of investigation include:

- Economic transmission upgrades or lack thereof;
- Entergy's wholesale purchasing practices, including the potential savings due to integration of independent power producers into its economic dispatch;
- The retirement of Entergy's old, inefficient gas- and oil-fired generation; and
- The addition of coal capacity to the generation portfolio of Entergy Louisiana, Inc.

Complaint

Pursuant to Rule 206 of the Commission's Rules of Practice and Procedure and Sections 205, 206, and 207 of the Federal Power Act ("FPA"), 16 U.S.C. §§ 824d, 824e, and 824f, the

Arkansas Public Service Commission ("Arkansas Commission" or "APSC") hereby submits this Complaint against Entergy Services, Inc., as the representative of Entergy Corporation ("Entergy") and its operating companies ("EOCs"), Entergy Arkansas, Inc. ("EAI"), Entergy Gulf States, Inc. ("EGS"), Entergy New Orleans, Inc. ("ENO"), Entergy Louisiana, LLC ("ELL"), and Entergy Mississippi, Inc. ("EMI"). By this complaint, the Arkansas Commission requests that this Commission establish a trial-type evidentiary hearing to investigate the prudence of certain of Entergy's practices that affect the EOCs' production costs. Additionally, the Arkansas Commission requests that the Commission exercise its authority under FPA Section 207 to determine the proper, adequate, and sufficient interstate transmission service provided by Entergy.

The filing of this Complaint was necessitated by the Commission's issuance of its Opinion Nos. 480, *Louisiana Public Service Commission, et al., v. Entergy Services, Inc., et al.*, 111 FERC ¶ 61,311 (2005), and 480-A, 113 FERC ¶ 61,282 (2005). In those opinions, the Commission ruled that, in order to maintain the rough equalization of production costs among the EOCs, discussed in more detail below, each EOC's production costs must be within a bandwidth of +/-11% of the Entergy system average production cost. Those decisions are now before the United States Court of Appeals for the District of Columbia Circuit, and the Arkansas Commission does not in this proceeding request any change to those opinions or any other alteration to the Entergy System Agreement cost allocations as deemed just, reasonable, and not unduly discriminatory by this Commission.

However, as a result of those opinions, the great majority of the EOCs' production costs, approximately 80%, which had previously been subject primarily to state retail jurisdiction, will begin to flow through the amended System Agreement's bandwidth. As a result, the Arkansas

Commission has little ability to capture the benefits of any cost reductions to EAI, and no ability to reduce costs to the other EOCs, even though those costs will directly affect EAI's payments under the bandwidth. The Arkansas Commission's only recourse is thus to institute a proceeding at this Commission to ensure that the *overall system costs borne by all the EOCs* are prudent, just, and reasonable. Moreover, certain of the practices that the Arkansas Commission believes should be investigated are uniquely in this Commission's jurisdiction, such as Entergy's wholesale purchasing practices and the planning and operation of its transmission system.

Background

Entergy Corp. is a public utility holding company whose retail utility operations are carried out through the EOCs specified above. Entergy Services, Inc. ("ESI"), is a subsidiary of Entergy Corp. that provides various accounting, computer, and other services to the other subsidiaries of the Entergy System. ESI acts as agent for Entergy Corp. and for the EOCs in matters related to the Entergy System Agreement before this Commission.

Costs among the EOCs are allocated at wholesale primarily by two rate schedules jurisdictional to this Commission.[1] The first is the Entergy System Agreement, an automatically-adjusting formula tariff which allocates energy, non-nuclear capacity, transmission, and other costs.[2] The second is the Unit Power Sales Agreement ("UPSA"), which allocates the costs of the Grand Gulf Nuclear Station ("Grand Gulf"), which is owned by Entergy subsidiary System Energy Resources, Inc. ("SERI"), among EAI, ELL, EMI, and ENO.[3] The UPSA and the

[1] Certain EOCs have also entered into bilateral wholesale contracts which allocate capacity, energy, and related costs pursuant to Entergy System Agreement Service Schedule MSS-4.

[2] The System Agreement amendments necessary and appropriate to implement Opinion Nos. 480 and 480-A are pending before the Commission in Docket No. EL01-88-004.

[3] EGS was acquired by Entergy in 1994 and was not assigned responsibility for costs under the UPSA.

System Agreement[4] were approved by this Commission in 1985 in its Opinion No. 234, *Middle South Energy, Inc.*, 31 FERC ¶61,305 (1985), *reh'g denied*, Opinion No. 234-A, 32 FERC ¶61,425 (1985), *aff'd in part sub nom Mississippi Industries v. FERC*, 808 F.2d 1525 (D.C. Cir. 1987); Opinion No. 292, 41 FERC ¶61,238 (1987), *reh'g denied*, Opinion No. 292-A, 42 FERC ¶61,091 (1988), *aff'd sub nom. City of New Orleans v. FERC*, 875 F.2d 903 (D.C. Cir. 1989), *cert. denied* 494 U.S. 1078 (1990). In Opinion No. 234, the Commission ruled that the System Agreement, in conjunction with the UPSA's nuclear cost allocations, would result in rates that are just, reasonable, and not unduly discriminatory. In Opinion No. 292, *supra*, the Commission reaffirmed its decision in Opinion No. 234, reasoning, in part, as follows:

> In other words, an allocation scheme that would not achieve a rough equalization of production costs on a demand basis would be, in the absence of a rational explanation, unduly discriminatory because there would be no basis for disparity among similarly situated entities.

41 FERC at 61,617.

On June 14, 2001, the Louisiana Public Service Commission ("LPSC"), which regulates the retail rates of ELL and a portion of those of EGS, and the City Council of New Orleans ("CNO"), which regulates the retail rates of ENO[5], filed a complaint before this Commission alleging that production costs among the EOCs were no longer "roughly equal" and that, as a result, the System Agreement was no longer just, reasonable, and not unduly discriminatory. CNO subsequently entered into a settlement agreement with Entergy, as a result of which it withdrew as a complainant. The Arkansas Commission, the Mississippi Public Service Commission ("MPSC"), and other parties intervened in opposition to this complaint.

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[4] The System Agreement has been amended since that time, but the cost allocation scheme remains essentially the same.

On June 1, 2005, the Commission issued its Opinion No. 480, in which it ruled that the EOCs' production costs were no longer roughly equal and that the System Agreement was therefore no longer just, reasonable, and not unduly discriminatory. The Commission directed that the System Agreement be amended so as to require that each EOC's production costs be within a bandwidth of +/-11% of the system average production cost. 111 FERC at PP 136, 142. That decision was affirmed on rehearing in Opinion No. 480-A, *supra*. Appeals of Opinion Nos. 480 and 480-A have been lodged in the United States Court of Appeals for the District of Columbia Circuit by the LPSC, the APSC and the MPSC jointly, and Arkansas Electric Energy Consumers ("AEEC"), where they are currently pending.

The result of the bandwidth, if affirmed on appeal, is that capacity and energy costs that had previously been regulated almost entirely at retail will be allocated subject to a wholesale tariff. The purpose of this Complaint is to ensure that these Commission-jurisdictional costs are just, reasonable, and prudently incurred. Moreover, as discussed below, the Commission should not delay its investigation into the prudence of Entergy's practices until those appeals have been resolved.

Jurisdiction

FPA Section 201(b), 16 U.S.C. § 824(b), provides that this Commission has jurisdiction over the sale of electric energy at wholesale and the transmission of electric energy in interstate commerce. FPA Section 205, in turn, requires that all rates and charges "made, demanded, or received" by a jurisdictional public utility be just and reasonable. The Commission's authority to set rates is set forth at FPA Section 206, which provides in part as follows:

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[5] CNO also regulates a small percentage of ELL's costs for customers located in New Orleans.

> Whenever the commission, after a hearing had upon its own motion or upon complaint shall find that any *rate, charge*, or classification, demanded, observed, charged, or collected by any public utility for any...sale subject to the jurisdiction of the Commission, or that any rule, regulation, *practice*, or contract *affecting such rate, charge*, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.

16 U.S.C. § 824(a) (emphasis supplied). Thus, both the rates charged by Entergy under its System Agreement and the practices affecting those rates and charges are subject to this Commission's jurisdiction. The operation of the bandwidth adopted in Opinion No. 480, if affirmed on appeal, will dramatically increase the costs flowing through the Entergy System Agreement so that virtually all of the EOCs' production costs and Entergy's practices affecting those costs are subject to this Commission's jurisdiction. Moreover, because the System Agreement is an automatically adjusting formula rate, the charges flowing through its service schedules and the bandwidth calculations will not be scrutinized for reasonableness and prudence by any regulator before they are assessed.

As described in the Affidavit of Dr. S. Keith Berry, attached hereto as Exhibit A, the +/- 11% bandwidth requires that the production costs of each EOC be calculated by a formula which will incorporate all of the EOCs' capacity and energy costs, excluding only those found by the Commission to be inappropriate for inclusion. The results will then be compared to the system average production cost. Any EOC whose costs are below 89% of the system average will make payments to those EOCs with costs above the System Average until the lower-cost EOC is at 89% of the system average. If any EOC is above 111% of the System Average, that Company would receive payments from the EOCs below the System Average. These payments and receipts would occur until all EOCs are within the +/- 11% bandwidth.

As explained in Dr. Berry's Affidavit, the result of the bandwidth is that the EOCs and their retail regulators have little ability or incentive to reduce production costs. For example, EAI's costs are projected to be below the bandwidth for the foreseeable future. Therefore any savings in production costs that it may achieve, on its own initiative or at the direction of the Arkansas Commission, will flow almost entirely to the EOCs with above-average costs, primarily to ELL and EGS. *The only savings that EAI can achieve is through a reduction in overall system costs.* Affidavit at ¶ 8. Conversely, the higher-cost EOCs--ELL and EGS--and their retail regulators will have little incentive to reduce costs because such reductions will primarily benefit EAI through a reduction in its payments. The result of these perverse incentives, absent this Commission's intercession, is unreasonably high overall system costs. The Arkansas Commission's only recourse to obtain just and reasonable costs for EAI and its customers is therefore for this Commission to ensure that the Entergy system is operated so as to ensure that all costs are reasonable and prudently incurred.

Additionally, FPA Section 207 authorizes the Commission to examine the adequacy and sufficiency of jurisdictional utilities' interstate services:

> Whenever the Commission, upon complaint of a State commission, after notice to each State commission and public utility affected and after opportunity for hearing, shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation….

As discussed in Dr. Berry's Affidavit, the EOCs' production costs are unnecessarily and imprudently inflated because of the inadequacy of Entergy's interstate transmission system. Specifically, Entergy has failed to remedy uneconomic transmission constraints, with the result that the EOCs, and in particular those EOCs with above-average production costs, are unable to access lower-cost purchased power available in the wholesale market. Affidavit at ¶ 22. The

Commission should exercise its power under FPA Section 207 to order Entergy to make all necessary upgrades to ensure that its transmission facilities provide reliable, adequate and economic service.

Relief Requested

The Arkansas Commission requests that this Commission institute an investigation, including a trial-type evidentiary hearing, into the prudence of all of Entergy's practices affecting production costs. The Arkansas Commission further requests that a refund effective date be set for the earliest possible date.[6] The information currently available indicates that there are at least three areas in which Entergy's practices should be investigated to ensure that the resulting costs are prudently incurred, just, and reasonable. These areas are detailed in Dr. Berry's Affidavit and fall into three general, inter-related areas: transmission, wholesale power purchasing, and generation. Additionally, as discussed above, the Commission should investigate the adequacy and sufficiency of Entergy's transmission system and direct that any inadequacy be promptly remedied.

Moreover, the Commission should not wait until the appeals of Opinion No. 480 have been resolved to begin its investigation into the prudence of Entergy's practices affecting jurisdictional rates. Opinion No. 480 directs that payments under the amended System Agreement begin in 2007, based on costs incurred in 2006. In its most recent 10-K, Entergy estimated that EAI's payments under the bandwidth, if affirmed on appeal, will be approximately

[6] As the Commission is well aware, FPA Section 206(c) prohibits refunds when their effect will be to shift costs among utility affiliates. However that prohibition is not applicable here; the FPA Section 206 remedy sought by the Arkansas Commission is a disallowance of costs found to be imprudently incurred. This remedy will not shift costs among the EOCs, but between the EOCs' customers and Entergy shareholders.

$358 million in 2007.[7] Efforts to ensure that these payments do not include imprudently incurred costs should begin as soon as possible. Many of the remedies that would eliminate those costs, such as the alleviation of uneconomic transmission constraints, will likely take years to implement. While ratepayers should of course not be required to pay imprudent costs in the interim, the limited refund period afforded under FPA Section 206 may be insufficient to completely shield ratepayers from their effects. Moreover, as discussed below, Entergy's practices with regard to transmission and wholesale purchases raise concerns as to their affect not only on Entergy's retail customers but also on the wholesale market in the Entergy region. Those problems will not be remedied, or even addressed, by the appeals of Opinion No. 480, and the Commission should not delay its investigation into those issues.

Transmission

The Arkansas Commission is aware that the Commission recently approved, subject to certain conditions, Entergy's proposal to contract with an Independent Coordinator of Transmission ("ICT") to perform certain functions for its transmission system. *Entergy Services, Inc.*, 115 FERC ¶ 61.095 (April 24, 2006). Like many stakeholders in the Entergy region, the Arkansas Commission expects that the ICT will bring significant improvements to the independence and transparency of the administration of the regional transmission system. However, implementation of the ICT will not, in and of itself, be sufficient to ensure that the production costs flowing under the Entergy system agreement are just, reasonable, and prudently incurred.

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[7] Of course, if the LPSC's arguments in favor of a narrower bandwidth are adopted, the resulting payments will be even more draconian.

As discussed in Dr. Berry's Affidavit, there is significant transmission congestion in the southern part of the Entergy footprint. This congestion has affected and, until remedied, will continue to affect not only reliability but also production costs insofar as it forecloses the opportunity for lower cost energy purchases. This congestion has been confirmed by studies by both the LPSC and CNO. The LPSC's Final Phase II Transmission Study Report, dated September 2005, projected a net present value of $206 million and $57 million for ELL and EGS-Louisiana ("EGS-LA"), respectively, for the 2004-26 period. Similarly, a September 21, 2004, cost benefit study was prepared by Entergy for CNO showing net benefits of $251 million and $39 million to ELI and EGS-LA, respectively. Affidavit at ¶ 22. Under the bandwidth adopted in Opinion No. 480, those cost reductions would inure not only to the benefit of ELL and EGS, but also to EAI, EMI, and ENO. Additionally, there are likely other economic upgrades that will reduce production costs that will be identified after discovery in this proceeding. The Arkansas Commission believes that the ICT's assumption of transmission planning responsibility for Entergy will ultimately lead to the alleviation of these constraints; however, the expected transmission upgrades will likely take years to bring to fruition. Entergy's ratepayers should not be required to bear any imprudent costs incurred in the interim as a result of Entergy's transmission planning. The Commission should investigate the prudence of Entergy's transmission expansion policies to date and disallow any costs determined to be imprudent.

A second concern is whether Entergy's provision of access to its transmission system is just, reasonable, and not unduly discriminatory. On December 17, 2004, the Commission issued an order under FPA Section 206 establishing an investigation into that issue as well as other related concerns. *Entergy Services, Inc.*, 109 FERC ¶ 61,288. However, the Commission has decided to hold that proceeding in abeyance pending its consideration of Entergy's proposal to hire an ICT to plan and perform certain administrative functions for its system. 110 FERC ¶ 61,296 (2005). Again, the Arkansas Commission believes that implementation of the ICT proposal will significantly alleviate those problems. However, that implementation will take a significant amount of time, and Entergy's customers should not be required to bear any imprudent costs incurred in the meantime. The Commission should investigate whether Entergy has prudently operated its transmission system and disallow any costs that were imprudently incurred prior to the ICT's assuming full responsibility for those functions. Moreover, if the ICT is not fully implemented for any reason, the Commission should re-institute its investigation into Entergy's transmission practices and examine whether they result in just, reasonable, and prudently incurred production costs.

Wholesale Power Purchases

There is no question that there is an abundance of competitive power generation in the Entergy region. There is a question, however, as to whether Entergy is prudently taking advantage of that generation to produce the lowest cost, just, reasonable, and prudently incurred rates to its customers. For example, as part of its ICT proposal, Entergy also proposed to institute a Weekly Procurement Program ("WPP"), whereby it would solicit competitive bids for its projected generation needs on a weekly basis. Entergy first proposed the WPP as part of its original ICT filing on March 31, 2004, in Docket No. ER04-699-000, after having received Commission guidance on its major elements in September 2003. *Entergy Services, Inc.*, 104 FERC ¶ 61,366 (2003). At a July 30, 2004, Technical Conference in New Orleans, Louisiana, Entergy stated that the WPP would result in an estimated annual savings of $30 million for every percentage point decrease in the use of its own gas- and oil-fired generation. In its order approving the ICT proposal, the Commission also approved the WPP program. However, Entergy has admitted that it there is no reason that it could not have implemented the WPP even in the absence of an approved ICT. Affidavit at ¶ 14. Nevertheless, three years have passed without Entergy's even attempting to implement this process independent of an ICT, and it is currently anticipated that it will not begin operations for an additional fourteen months following the Commission's April 24, 2006, order. 115 FERC P 296. Entergy has offered no reason that these cost reductions should have been delayed to this extent, and customers should not be required to bear costs imprudently incurred due to its failure to timely obtain for its customers the cost reductions resulting from the WPP.

Moreover, Entergy's failure to obtain the benefits of the WPP raises questions as to whether its other wholesale power purchasing practices have been prudently managed to obtain the benefits of competitive generation for its customers. For example, certain independent power producers have maintained that significant production cost reductions could be achieved through the integration of independent generators into Entergy's economic dispatch.[8] While it is not possible at this time to specifically calculate the benefits that may be obtained through such integration, the benefits of expanded pay-as-bid energy markets could result in significant cost savings. Affidavit at ¶ 19. The Commission should investigate the accuracy of these assertions and further examine whether Entergy has prudently managed its other wholesale purchases so as to result in just, reasonable, and prudently incurred costs.

[8] *See, e.g.*, Motion for Leave to Intervene and Comment of the Electric Power Supply Association, at 7-8, attached as Exhibit B.

Generation

There are at least two areas in which Entergy's generation planning practices should be closely scrutinized to determine whether they result in production costs that are just, reasonable, and prudently incurred. The first is Entergy's failure to retire its aging, inefficient oil- and gas-fired generation, most of which is owned by ELL and EGS. A March 2, 2005, LPSC study investigated the economic effects of the retirement of a portion of over 14,000 MW of such generation. According to the LPSC's study, the retirement of approximately 3000 MW of such units would result in an approximately $60 million per year cost reduction over the 2006-12 period. Under the operation of the +/- 11% bandwidth, those cost reductions to ELL would reduce overall system costs and decrease EAI's payments to the other EOCs. Affidavit at ¶ 21. Entergy's failure to capture these cost savings for its customers should be investigated to determine whether it results in rates that are not just, reasonable, and prudently incurred.

A second area of investigation is whether the Entergy system should have begun construction or acquisition of a new coal plant in Louisiana for the benefit of customers of ELL and/or EGS. ELL is currently deficient in baseload capacity, and its continued reliance on gas-fired generation was a primary reason cited by the Commission for the current disparities in production costs. 111 FERC at PP 16, 28. Such new coal generation would lower overall system production costs, and, under the operation of the bandwidth, reduce EAI's payments to the other EOCs. Affidavit at ¶ 24.

Two other generation-related practices that should be investigated for prudence are Entergy's gas-hedging and purchasing practices and its demand-side management plans. While in the past these activities have been considered the province of retail regulation, the operation of the +/-11% bandwidth, as discussed above, will spread the costs and benefits of any such programs among all the EOCs. This Commission should investigate Entergy's activities in these areas and disallow any costs determined to be imprudent. Affidavit at ¶¶ 20, 25.

Compliance with Rule 206(b)

.The Arkansas Commission has provided, to the extent that it is available, the information required by Rule 206(b)(1), (2), (3), (4), (5), (7), and (8). A form of notice, as required by Rule 206(b)(10) is attached. In response to Rule 206(b)(6), there is, to the Arkansas Commission's knowledge, no other proceeding in which these issues are currently being addressed. In response to Rule 206(b)(9), the Arkansas Commission believes that, due to the complex and potentially controversial nature of this complaint, it does not believe that informal or formal dispute resolution procedures will be fruitful at this time; however, the Arkansas Commission believes that some form of dispute resolution may be fruitful following discovery and further development of the facts and issues. The Arkansas Commission is, as always, open to reasonable settlement discussions.

Conclusion

Retail regulators generally have both the ability and the incentive to reduce the production costs of jurisdictional utilities to the benefit of ratepayers. Following the issuance of Opinion No. 480, however, that is no longer the case for the Arkansas Commission and Entergy's other retail regulators. Instead, the Arkansas Commission's only recourse to ensure just and reasonable rates is through action by this Commission to ensure that the Entergy system's overall production costs are just, reasonable, and prudently incurred. This Commission should therefore establish a trial-type evidentiary hearing to investigate the prudence of Entergy's operations as described above, as well as set a refund effective date at the earliest possible time. Following such hearing, any costs determined to be imprudent should be disallowed and not included in production costs bandwith calculations. Additionally, the Commission should exercise its authority under FPA Section 207 to direct Entergy to provide adequate interstate transmission services for its customers.

Respectfully submitted,

Mary W. Cochran, General Counsel
Randolph Hightower, Commission Counsel
Ted Thomas, Commission Counsel
Arkansas Public Service Commission
1000 Center Street
P.O. Box 400
Little Rock, AR 72203-0400

Counsel for the
Arkansas Public Service Commission

CERTIFICATE OF SERVICE

I, Mary W. Cochran, Counsel for the Arkansas Public Service Commission, hereby certify that a copy of the Complaint of the Arkansas Public Service Commission has been served on the Respondent, affected regulatory agencies, and all others the complainant reasonably knows may be expected to be affected by the complaint via electronic service or facsimile as provided by the Commission Rules of Practice and Procedure, this 7th day of June, 2006.

Mary W. Cochran

Mary W. Cochran

EXHIBIT A

EXHIBIT A

STATE OF ARKANSAS)

COUNTY OF PULASKI)

AFFIDAVIT

DR. S. KEITH BERRY, first being duly sworn upon his oath, deposes and states the following:

1. My name is Dr. S. Keith Berry. I am Professor of Economics and Business at Hendrix College in Conway, Arkansas, Director of the Center for Entrepreneurial Studies at Hendrix College, and a principal in the firm of Economic & Consulting Group, Inc. I received my B.A. in mathematics from Hendrix College, and my Ph.D. in economics from Vanderbilt University, where one of my economic fields of specialization was econometrics. Beginning in July 1979, I served on the Staff of the Arkansas Public Service Commission as Manager of the Finance and Rate Sections and then as Director of Research and Policy Development. Beginning in September 1989, I returned to teaching at Hendrix College. I have submitted testimony in more than seventy different proceedings before public service commissions or other regulatory agencies, including testimony or affidavits before this Commission in Docket Nos. ER03-583-000, ER03-753-000, EL01-88-000, EL00-66-000, EC99-18-000, EC98-40-000, ER98-2770-000, ER98-2786-000, ER95-53-000, ER95-1042-000, EL94-13-000, EL94-7-000, ER94-898-000, ER92-341-000, EL92-35-000, EC92-21-000, EL92-36-000, EL90-16-000, ER90-16-000, ER89-678-000, EL86-58-000, EL86-59-000, and RM-80-36-000. My publications include articles in the *American Economic Review*, *Journal of*

Regulatory Economics, *Land Economics*, the *Energy Journal* (coauthor), the *Journal of Economics and Business*, *The Quarterly Review of Economics and Business*, *The Financial Review*, the *Eastern Economic Journal*, *Managerial and Decision Economics*, *Public Choice*, and the *Review of Industrial Organization*. I have made presentations concerning utility regulation and the cost of capital at the NARUC Advanced Studies Program, the Eastern NARUC Utility Rate Seminar, the Western NARUC Utility Rate Seminar, the National Conference of Regulatory Utility Commission Engineers, and the Annual Conference of the Institute of Public Utilities. While on the Staff of the Arkansas Public Service Commission I served on the NARUC Subcommittee on Electricity and the Research Advisory Committee of the National Regulatory Research Institute (Deputy Chairman, 1988-89). I am currently a member of the American Economic Association and the Southern Economic Association. My *Curriculum Vita* is provided in Attachment A.

2. In FERC Docket No. ER82-483-000 and ER82-616-000, the Commission held that the production costs of the four Entergy Operating Companies, Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), and Entergy New Orleans, Inc. ("ENO"), should be in "rough production cost equalization." In order to accomplish that goal, the Commission assigned specific portions of Grand Gulf 1, owned by System Energy Resources, Inc. ("SERI") to the four Entergy Operating Companies ("EOCs"). In 1994, Entergy acquired Gulf States Utilities, now Entergy Gulf States, Inc. ("EGS"),

and EGS became a signatory to the System Agreement on substantially the same terms as the other EOCs, although it was not assigned any cost responsibility for Grand Gulf.

3. Recently in Opinion No. 480 in Docket No. EL01-88-000, the Commission more precisely defined "rough production cost equalization" as a +/- 11% bandwidth wherein all EOCs' production costs, defined as $/Mwh, are between 89% and 111% of the Entergy System Average production cost.[1] If any EOC is below 89% of the System Average, that EOC will make payments to those EOCs that are above the System Average until the lower-cost EOC(s) is at 89% of the System Average, even if the higher –cost EOCs are less than 111% of the System Average. If any EOC is above 111% of the System Average, that Company would receive payments from those EOCs below the System Average. These payments and receipts would occur until all EOCs are within the +/- 11% bandwidth. If all EOCs are already within the +/-11%bandwidth, no payments are made.

4. This bandwidth remedy would be accomplished by amending the Entergy System Agreement, whose Service Schedules operate as formula rates. According to Section 3.01 of the System Agreement, an objective of the Agreement is to provide a basis for equalizing among the Companies any imbalance of costs

[1] These production costs will be calculated using formulas which incorporate all of the EOC's fixed and variable production costs, excluding those found by the Commission to be inappropriate for inclusion.

associated with the construction, ownership and operation of such facilities as are used for the mutual benefit of all the Companies.

5. The System Agreement has six Service Schedules. Service Schedule MSS-1 provides the basis for equalizing the capability and ownership costs for System reserves. Service Schedule MSS-2 provides the basis for equalization of the ownership costs associated with Inter-Transmission Investment (generally facilities of 230 kV or higher). Service Schedule MSS-3 provides for the after-the-fact allocation of energy costs among the EOCs. Service Schedule MSS-4 provides the basis for making a unit power purchase between EOCs and/or the sale of power purchased by another EOC. Service Schedule MSS-5 provides the basis for the distribution among the EOCs of the net balance received from sales to others for the joint account of all the EOCs. Service Schedule MSS-6 provides the basis for distribution among the EOCs of the costs of the System Operations Center.

6. Because of Opinion No. 480, the regulatory paradigm in the Entergy region, which has been in place for the last fifty years, has dramatically changed. The retail regulators of the EOCs no longer have significant control over the production costs of their respective EOCs. This will necessitate a profound change in the manner in which the retail regulators attempt to minimize their jurisdictional EOCs' production costs. Because of the bandwidth remedy, retail

regulators will look to the FERC to minimize the production costs of their respective EOCs.

7. For the foreseeable future, it is likely that EAI will be below the 89% lower bandwidth cutoff. This means that EAI will be consistently making payments to EOCs, primarily ELL and EGSI, which are expected to have costs above the System Average. Prior to implementation of the bandwidth, if EAI reduced annual production costs by, for example, $50 million, the retail ratepayers would expect to see an annual rate reduction of about 94% of that, or $45 million (approximately 6% of the cost reduction would go to EAI's wholesale customers). This provided significant incentives and ability for the Arkansas Public Service Commission ("APSC") to monitor and regulate, as appropriate, all production cost decisions made by EAI. Those incentives and ability, while still present, have been significantly diminished by the bandwidth remedy. Any reduction in EAI's production costs will result in greater payments from EAI to other EOCs, which ultimately diminishes the value to EAI ratepayers of that reduction.

8. In Appendix 1 I illustrate this with a numerical example using numbers that approximate costs and load over the next few years on the Entergy System. As shown there, when EAI decreases its production costs two relevant cost parameters change:

(1) The System Average 89% bandwidth lower limit decreases; and

(2) EAI's stand-alone costs decrease.

The net production cost savings to EAI ratepayers, comprehending these two effects, is significantly less for EAI retail and wholesale ratepayers than keeping 100% of the production cost reduction, and represents a significant reduction in the APSC's jurisdiction. *The only benefit that EAI receives is due to the overall reduction in System costs; the reduction in EAI stand-alone costs is totally lost because of the increase in payments to the other EOCs.*

9. The +/- 11% bandwidth remedy gives significant incentive to the APSC to attempt to obtain significant reductions in the production costs of the other EOCs. Since the dominant feature of payments and receipts for the next several years is that any payments made by EAI will move all of the other EOCs' production costs closer to the System Average, the incentives for EAI and the APSC are focused solely on the reduction in the System Average production cost. An example of this is also shown in Appendix 1. Instead of reducing EAI's production costs, assume that EGS or ELL reduces its production costs by an amount equivalent to that shown in the first example of Appendix 1. *With the bandwidth remedy, the net benefit to EAI there is equivalent to the net benefit of EAI reducing its own production costs.* This is not just a coincidence. Given the specific bandwidth remedy chosen by the Commission, and the likelihood that EAI's production costs will be below the 89% bandwidth lower limit, EAI

ratepayers will benefit by an the same amount of production cost savings whether it originates at EAI or elsewhere on the System.

10. This loss in effective retail jurisdiction would be of little import if production costs were a relatively small part of the EOCs' total revenue requirement. However, production costs are a significant percentage of total costs on the Entergy System. For example, in 2001 approximately 72% of the EOCs' total costs were production costs. This percentage will likely be greater with the run-up in gas prices since then.

11. Conversely, for EOCs above the 111% upper bandwidth limit, there are diminished incentives to reduce production costs. This is shown in the third example in Appendix 1. Therein it is assumed that ELL and the LPSC jointly develop a plan to reduce ELL annual production costs. Prior to the imposition of the bandwidth remedy, that reduction would have inured solely to the benefit of the ELL ratepayers. However, with the bandwidth remedy, that is not the case. The net savings to ELL ratepayers, including the effects of bandwidth payments/receipts, is substantially less than the stand-alone reduction. Note that two relevant cost parameters change in that case:

(1) The System Average 111% bandwidth upper limit decreases; and

(2) ELL's stand-alone costs decrease.

The example in Appendix 1 demonstrates how the bandwidth remedy significantly diminishes the incentives for high-cost EOCs and their retail regulators to reduce production costs. This diminished incentive also illustrates why the APSC must look to the FERC to minimize the production costs of other EOCs.

12. Because of all of the above, the Commission should investigate the prudence of all of Entergy's current practices that affect production costs, and disallow any costs determined to be imprudent. It is important that this investigation begin now for a number of reasons. First, the "cost clock" is currently "ticking." EAI will start making bandwidth-related payments beginning next year based on production costs incurred on the Entergy System in calendar year 2006. Those costs are being experienced right now. The sooner that Entergy's production costs can be decreased the sooner that EAI ratepayers will be provided relief from the significant projected payments beginning in the year 2007.

13. Those payments are expected to be of major magnitude for EAI. As reported in Entergy's 2005 10-K, the average annual EAI payment is projected to be $328 million over the 2007-2010 time period, with a range of $293 million to $385 million per year. Those payments are premised upon natural gas prices ranging from $6.83/mmBtu to $8.74/mmBtu. If gas prices are higher than projected by

Entergy in that 2005 10-K, the impact on EAI ratepayers will be even greater. For every increase in natural gas prices of $1/mmBtu the EAI payments increase by at least $70 million per year. (Entergy 2005 10-K, pp. 28-9). The average $328 million annual increase represents approximately a 20% rate increase to EAI ratepayers.

14. Finally, this Commission should immediately undertake such investigations because any necessary changes required by the Commission will take some time before any beneficial results for EAI ratepayers can be obtained. This is because most changes in generation and transmission involve capital expenditures which by their very nature take significant time to complete.

15. There are a number of areas that are ripe for such a FERC investigation. For example, Entergy's proposal for an Independent Coordinator of Transmission ("ICT") was recently approved by the Commission. As shown in Attachment B, which is a document distributed by Entergy at a July 30, 2005 Technical Conference, Entergy has projected that the present value of the ICT savings for Entergy's ratepayers, relative to the status quo is between $240 million to $360 million.

16. Part of that proposal is a Weekly Procurement Process which would result in overall annual savings of $30 million per year for every percentage point decrease in Entergy's oil/gas generation (resulting from increased purchases from

merchants). The WPP is designed to facilitate the granting of more transmission service and to allow for the displacement of existing network resources in favor of cheaper alternatives. This will be accomplished through a simultaneous optimization of existing service and new requests subject to transmission constraints. As part of this WPP, Entergy will have the opportunity to purchase from wholesale producers and to economically integrate independent power producers into Entergy's system dispatch. The APSC expects that additional significant production cost savings will inure to the benefit of Entergy ratepayers if the ICT/WPP process results in significant development of competition in the Entergy region. These savings will decrease overall System costs and, because of the bandwidth remedy, decrease EAI's payments to the other EOCs. However, it is not clear why the implementation of the WPP has been delayed pending the Commission's decision on the ICT. At a Technical Conference at New Orleans on July 29-30, 2004, an Entergy representative stated, in response to a question from Commission Chair Pat Wood:

> Mr. Chairman, the weekly procurement was initially proposed on its own...[I]t was proposed on its own and it could have been implemented and could be implemented on its own...So if you're asking is there an option for Entergy to stand alone, do the WPP without the ICT, I think that technically that option exists. It's not the company's proposal, but I think that option exists. (Testimony of Michael Schnitzer).

Expedited implementation of the WPP would have resulted in savings of millions of dollars to Entergy ratepayers. The Commission should investigate the prudence of Entergy's delay in implementing the WPP process and disallow any costs determined to be imprudent.

17. Additionally there are a number of areas for cost savings which are not covered by the ICT. This does not mean that the ICT is deficient; it is only intended to address a specific and limited number of areas that have effects on Entergy ratepayers' costs.

18. One example is that Entergy may have opportunities, beyond those encompassed in the WPP, to purchase power products with a variety of durations and characteristics from the wholesale market. Those purchases will likely be economically advantageous to Entergy ratepayers. The Commission should investigate the prudence of Entergy's wholesale purchasing practices and policies and disallow any costs determined to be imprudent.

19. There are approximately 17,000 MW of merchant power plants being built in the Entergy control area. As these plants are completed, there will be opportunities to integrate their generation of electricity into the Entergy System dispatch, which could result in significant savings to Entergy ratepayers. In order to give an estimate of the magnitude of potential savings available from a more comprehensive security-constrained economic dispatch in the Entergy balancing area, I have estimated the total amount of fuel savings for 2004 and 2005 if the energy from Entergy's gas-fired units had been *totally* displaced by merchant

plant gas-fired units with 8000 Btu/Kwh heat rates. For the years 2004 and 2005 those savings are in the range of $505 million to $669 million per year. Going forward, for gas prices between $7/mmBtu and $10/mmBtu, the potential annual fuel savings is between $552 million and $795 million. These maximum savings will change in the same direction as do gas prices. Of course, there will clearly be offsetting costs associated with the necessary transmission enhancements and expansions, and there will likely be issues associated with the ease of integrating the merchant units' ramp rates, minimum and maximum outputs, voltage support, start-up times, down times, credit-worthiness, etc. into Entergy's economic dispatch. Nevertheless there is potentially a significant amount of savings available for Entergy ratepayers from more fully integrating merchant units into the Entergy dispatch. It is to be hoped that the WPP will obtain some of the cost savings, but the WPP is not intended to be a complete security-constrained economic dispatch. The WPP is simply a first, and necessary, step, which the APSC supports. With WPP experience and advances in software technology applicable to dispatching processes, additional programs could be developed so as to allow Entergy to take full advantage of this potential cost savings. Four years is a long time to not fully access this amount of savings, and there is nothing in the Commission's ICT/WPP Order ("ICT/WPP Order") of April 24, 2006 in Docket No. EL05-1065-000 that precludes such additional programs. Examples of these additional programs are day-ahead and real-time energy and ancillary pay-as-bid markets, provision of automatic generation control to non-affiliates (discussed in Paragraph 280 of the ICT/WPP Order), and inclusion of demand response resources (Discussed in Paragraph 295 of the ICT/WPP Order). In particular, one of the reasons that Entergy was opposed to day-ahead and real-time markets in the context of the WPP was that such markets are more appropriate to the SeTrans RTO (104 FERC ¶ 61,336, P 29 (2003).). At that time, approximately three years ago, SeTrans was still a viable possibility. That is no longer the case. Therefore, it would be appropriate to explore that option as soon as possible. The Commission should investigate Entergy's dispatching policies and procedures so as to insure that the production of those merchant plants is prudently integrated into Entergy's system dispatch. Further, the Commission should disallow any costs determined to be imprudent.

20. The southern end of the Entergy System is dependent on natural gas-fired generation. The recent run-up in natural gas prices is a major explanation as to why the System is allegedly no longer in "rough production cost equalization."[2] Consequently, any significant excursions of natural gas prices, and any gas hedging costs, will have indirect effects on EAI through the operation of the +/- 11% bandwidth. Entergy currently engages in "gas hedging" for all EOCs except for EAI. This area is not addressed by the ICT Protocols. The Commission should investigate the prudence of Entergy's gas purchasing gas hedging practices and disallow any costs determined to be imprudent.

21. Also, there are opportunities for economically advantageous retirement of Entergy's aging oil and gas fleet. For example, the Louisiana Public Service

[2] Another important factor is the significant accumulated depreciation of EAI's coal and nuclear plants.

Commission ("LPSC") recently completed a plant retirement study, dated March 2, 2005, shown in Attachment C. That study investigates the issue of retiring some of the more than 14,000 MW of old inefficient gas/oil capacity, approximately 65% of which is owned by ELL and EGSI. . The new units would operate at a 7,700-8,500 BTU/kwh heat rate, while many of the older units have heat rates in excess of 10,000 BTU/kwh. The new units provide two sources of energy savings: heat rate efficiency advantages over retired units and displacement of economy purchases. As shown in that study, with 3000 MW of retirements and the retirement of one unit in Amite South, the LPSC Staff expects ELI to realize approximately $60 million in net savings per year over the 2006-12 period. Because of the bandwidth remedy, these savings will decrease overall System costs and decrease EAI's payments to the other EOCs. Generator retirements are not addressed by the ICT Protocols. The Commission should investigate the prudence of Entergy's policies and practices with regard to plant retirements and disallow any costs determined to be imprudent.

22. For some time now, the Southern part of the Entergy system has been subject to significant transmission congestion. This has impacts on both reliability and the level of production costs. In particular, lower cost energy purchases both from within and outside the Entergy region have likely been foreclosed. While the ICT Protocols identify possible Economic Upgrades, it will be up to Entergy to pursue those opportunities for the benefit of its ratepayers. The LPSC recently issued a Final Phase II Transmission Study Report, which was prepared by Entergy

Services in response to the LPSC Commission Order No. U-233356-Subdocket A, February 9, 2004. As shown in Attachment D, that analysis projects that with a targeted transmission expansion, the present value of the net benefits over the 2004-2026 period will be $206 million and $57 million for ELI and EGSI-La., respectively. Most of these transmission projects are in Louisiana. A more recent transmission cost/benefit study report was prepared on September 21, 2004 by Entergy for the Council of the City of New Orleans, which is attached as Attachment E. As shown there, the present value of the net benefits of targeted transmission expansion is $251 million to ELL and $39 million EGSI-La. Because of the bandwidth remedy, these savings will decrease overall System costs and decrease EAI's payments to the other EOCs. The Commission should investigate the prudence of Entergy's economic transmission expansion and upgrade policies and practices and disallow any costs determined to be imprudent.

23. Because of the bandwidth remedy, all Entergy ratepayers, including EAI's, will benefit from economically efficient expansion and enhancement of transmission in the southern part of Entergy's System. Those additional transmission costs will not be borne solely by Entergy's Louisiana ratepayers. Service Schedule MSS-2 of the Entergy System Agreement provides for full equalization of the costs of transmission facilities of 230kV and above based on load responsibility ratios. Since EAI's load responsibility ratio is approximately 22%, EAI ratepayers will pay for approximately 22% of the high voltage transmission facilities of any expansion or enhancement.

24. The southern part of the Entergy System has been baseload deficient for some time and likely needs to build a new coal plant in Louisiana in order to provide more baseload plant in that region. In a recent Request for Proposals, Entergy has indicated a need for a Baseload Solid Fuel plant, presumably coal, no later than December 31, 2012. Such baseload plants will lower the overall System production cost average and, because of the bandwidth remedy, decrease EAI's payments to the higher cost EOCs. The ICT Protocols do not address the issue of baseload plant expansion. It is unclear why Entergy has delayed for so long the construction of a coal plant on the southern end of the System. The Commission should investigate the prudence of Entergy's generation supply expansion plans and disallow any costs determined to be imprudent.

25. Economically efficient demand-side management will likely prove advantageous to Entergy ratepayers as well. Management of electricity demand becomes increasingly important in an era of high energy prices. Conservation of energy helps the consumer reduce the total electricity bill, improves the comfort quality of the home, allows the customer to take action to control increasing costs, makes for a less volatile price of electricity and natural gas, reduces emissions of air pollution, and, in the long-run, helps to restrain further energy price increases. Specific programs to manage demand can be targeted to reduce peak demand, which reduces the use of high cost generation resources and delays construction or purchase of additional generation resources. Demand-side management

programs may also promote greater use of energy in off-peak periods, which may improve operating efficiency of the generation fleet. Demand response markets function to truncate the hourly increase of a "hockey stick" shaped supply price curve. The ICT Protocols do not address the issue of demand management plans. The Commission should investigate the prudence of Entergy's demand management plans and disallow any costs determined to be imprudent.

26. There are probably other areas, such as unit repowering and unit uprates, not addressed in the ICT Protocols, where economically advantageous production cost ratings can be achieved. Because of the bandwidth remedy, these production cost savings will decrease overall System costs and decrease EAI's payments to the other EOCs. The Commission should investigate the prudence of all of Entergy's practices and procedures that affect production costs and disallow any costs determined to be imprudent.

AFFIDAVIT

STATE OF ARKANSAS)
)
COUNTY OF PULASKI)

S. KEITH BERRY, first being duly sworn upon hi oath deposes and states:

1. The foregoing affidavit is true to the best of my knowledge and belief.

Dr. S. Keith Berry
Dr. S. Keith Berry

Subscribed and sworn to me this 7th day June, 2006.

REBEKAH GILBERT
NOTARY PUBLIC-STATE OF ARKANSAS
FAULKNER COUNTY
My Commission Expires 2-14-2014

Rebekah Gilbert

APPENDIX 1

APPENDIX 1

Reduction in EAI Production Costs

Assume that EAI's load responsibility ratio is 22% with 25,000,000 Mwh of EAI annual load, and 113,636,637 Mwh of Entergy System annual load. Also assume that EAI's production cost is $45/Mwh and the System Average production cost is $55/Mwh. In order for EAI to be at 89% of the System Average, it will have to make payments that get EAI to a production cost of .89 X $55/Mwh = $48.95/Mwh. Consequently, EAI will have to make annual payments to the other EOCs of :

($48.95 - $45) X 25,000,000 = $98,750,000.

Now assume that EAI and the APSC jointly develop a plan to reduce EAI annual production costs by $50 million. Prior to the imposition of the bandwidth remedy, that $50 million would have inured to the benefit of the EAI retail and wholesale ratepayers. Total stand-alone production costs would be:

($45 X 25,000,000) -$50,000,000 = $1,075,000,000.

However, with the bandwidth remedy, that is not the case.[1] The net savings to EAI ratepayers is only $9,750,000, which is only 20% of the original $50 million production cost reduction. Note that two relevant costs changed:

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[1] From EAI's perspective there are two relevant changes associated with the reduction in production costs. First, the System Average production cost will decrease by $50,000,000 to

(1) The System Average 89% bandwidth lower limit decreased from

$48.95/Mwh to $48.56/Mwh; and

(2) EAI's stand-alone costs decreased from $45/Mwh to $43/Mwh.

The net savings to EAI ratepayers, comprehending these two effects, is then

$50,000,000 - $40,250,000 = $9,750,000,

This is significantly worse for EAI retail and wholesale ratepayers than keeping 100% of the production cost reduction, and represents a significant reduction in the APSC's jurisdiction. *The only benefit that EAI receives in this case is due to the overall reduction in System costs; the reduction in EAI stand-alone costs is totally lost because of the increase in payments to the other EOCs.*

(113,636,637 Mwh X $55) -$50,000,000 = $6,250,015,035 - $50,000,000 = $6,200,015,035. This equates to a System Average production cost rate of $6,200,015,035/113,636,637 = $54.56/Mwh. Second, EAI's stand-alone production costs decreased to $1,075,000,000/25,000,000 = $43/Mwh. After this production cost reduction, EAI is still below the 89% lower bandwidth limit, which is now .89 X $54.56 = $48.56/Mwh. EAI now has to make payments to the other EOCs of ($48.56 - $43) X 25,000,000 Mwh = $139,000,000. Although EAI's stand-alone costs have decreased by $50,000,000, EAI's payments to other EOCs have increased by $139,000,000 - $98,750,000 = $40.25 million.

Reduction in ELL/EGS Production Costs

Instead of reducing EAI's production costs, assume that EGS or ELL reduces production costs by $50,000,000. As shown in the example above, the System Production Costs are now

(125,000,000 Mwh X $55) -$50,000,000 = $6,200,015,035.

This equates to a System Average production cost rate of $54.56. EAI's stand-alone production costs have not changed and remain at $45/Mwh and EAI is still below the new 89% lower bandwidth limit, which is now .89 X $54.56 = $48.56. As a result of this $50,000,000 reduction elsewhere in the System, EAI's payment falls to ($48.56 - $45) X 25,000,000 Mwh = $89,000,000. This is a reduction in payments by EAI of $98,750,000 - $89,000,000 = $9,750,000 *which is equivalent to the net benefit of EAI reducing its own production costs by $50,000,000.* This is not just a coincidence. Given the specific bandwidth remedy chosen by the Commission, and the likelihood that EAI's production costs will be below the 89% bandwidth lower limit, EAI ratepayers will benefit by an the same amount of production cost savings whether it originates at EAI or elsewhere on the System.

Diminished Incentives for High Cost EOCs to Reduce Production Costs

Conversely, for EOCs above the 111% upper bandwidth limit, there are diminished incentives to reduce production costs. Assume that ELL has a load responsibility ratio of approximately 31% with 35,000,000 Mwh of ELL annual load, and 113,636,637 Mwh of Entergy System annual load. Also assume that ELL's production cost is $65/Mwh and the System Average production cost is $55/Mwh. In order for ELL to be at 111% of the System Average, it will have to receive payments from low-cost EOC(s) that get ELL to a production cost of 1.11 X $55 = $61.05. Consequently, high-cost ELL will receive :

($65 - $61.05) X 35,000,000 = $138,250,000.

Now assume that ELL and the LPSC jointly develop a plan to reduce ELL annual production costs by $50 million. Prior to the imposition of the bandwidth remedy, that $50 million would have inured solely to the benefit of the ELL ratepayers. Total stand-alone production costs would be ($65 X 35,000,000) -$50,000,000 = $2,225,000,000. However, with the bandwidth remedy, that is not the case. The net savings to ELL ratepayers is $ 17,100,000, which is only 34% of the original ELL-originated production cost reduction of $50 million. From ELL's perspective there are two relevant changes associated with the reduction in production costs. First, the System Average production cost will decrease by $50,000,000 to:

(113,636,637 Mwh X \$55) -\$50,000,000 = \$6,200,015,035.

This equates to a System Average production cost rate of \$6,200,015,035/113,636,637 = \$54.56/Mwh. This is the same System production cost rate we obtained when EAI reduced its production costs by \$50,000,000. Second, ELL's stand-alone production costs decrease to \$2,225,000,000/35,000,000 = \$63.57/Mwh. After this production cost reduction, ELL is still above the 111% upper bandwidth limit, which is now 1.11 X \$54.56 = \$60.56/Mwh. Note that two relevant costs changed:

(1) The System Average 111% bandwidth upper limit decreased from \$61.05/Mwh to \$60.56/Mwh; and

(2) ELL's stand-alone costs decreased from \$65/Mwh to \$63.57/Mwh.

ELL now receives payments from low-cost EOCs of (\$63.57 - \$60.56) X 35,000,000 Mwh = \$105,350,000. Although ELL's stand-alone costs have decreased by \$50,000,000, ELL's receipts from other EOCs have decreased by:

\$138,250,000 - \$105,350,000 = \$32.9 million.

The net savings to ELL ratepayers is then \$50,000,000 - \$32,900,000 = \$17,100,000, which is only 34% of the original ELL-originated production cost reduction. This example demonstrates how the bandwidth remedy significantly diminishes the incentives for high-cost EOCs to reduce production costs. This diminished incentive also illustrates why the APSC must look to the FERC to minimize the production costs of other EOCs.

ATTACHMENT A

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EDUCATION

Ph.D., Economics
Vanderbilt University, 1979

B.A., Mathematics
Hendrix College, 1973

PREVIOUS POSITIONS

Chair, Department of Economics and Business
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Associate Professor of Economics and Business
Hendrix College, 1994-2002

Assistant Professor of Economics and Business
Hendrix College, 1989-1994

Director of Research and Policy Development
Arkansas Public Service Commission, Little Rock, AR, 1986-1989

Manager of Rates and Finance Sections
Arkansas Public Service Commission, Little Rock, AR, 1979-1986

Instructor/Assistant Professor of Economics and Business
Hendrix College, Conway, AR, 1977-1979

Instructor
Vanderbilt University, 1976-77

HONORS AND AWARDS

Wincott Visiting Research Fellowship
University of Buckingham, United Kingdom, Fall, 1997

Earhart Fellowship (with Nicholas Georgescu-Roegen)
Vanderbilt University, 1975-1976

Graduate School Assistantship
Vanderbilt University, 1973-1976

Mosley Economics Award
Hendrix College, 1973

Hogan Math Award
Hendrix College, 1972

Alpha Chi (scholastic),
Hendrix College

Rensselaer Math and Science Award, 1968

COURSES TAUGHT

Managerial Economics (graduate level), 1998-Present, Hendrix College
Environmental Economics, 2000-Present, Hendrix College
Industrial Organization, 1992-Present, Hendrix College
Intermediate Microeconomics, 1991-93, 2001-present, Hendrix College
Survey of Economics, 1992-2000, Hendrix College
Investments, 1990-93, Hendrix College
Western Intellectual Traditions, 1995-99, Hendrix College
Money, Banking, and Credit, 1989-99, Hendrix College

Principles of Microeconomics, 1989-present, Hendrix College
International Economics, 1978, Hendrix College
Intermediate Statistics, 1979, Hendrix College
Intermediate Macroeconomics, 1979, Hendrix College
Money, Banking, and Credit, 1978, Hendrix College
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"Interest Rate Risk and Utility Bond and Dividend Yields," 1992 Western Economic Association Convention.

"Scaling Up Nuclear Decommissioning Costs," NARUC Advanced Regulatory Studies Program, Williamsburg, VA, 1992.

"Assessing Factors That Determine Utilities' Allowed Returns on Equity: A Risk-Adjusted Institutional Approach," (with Timothy Mason), 1989 Southern Economic Association Convention.

"The Grand Gulf Experience," Sixty-Fifth National Conference of Regulatory Utility Commission Engineers, Hot Springs, AR, 1987.

"Some Fundamental Principles in the Determination of a Utility's Cost of Capital," Seventh Annual Western Utility Rate Seminar, Salt Lake City, Utah, 1987.

"A Critique of Various Phase-in Plans," NARUC Advanced Regulatory Studies Program, Williamsburg, VA, 1986.

"Principles in the Determination of a Utility's Cost of Capital," Thirteenth Annual Eastern NARUC Utility Rate Seminar, Ft. Lauderdale, Florida, 1985.

"Nuclear Unit Construction and Electric Utilities' Cost of Capital," Western Economic Association Convention, 1984.

"Current Issues in Utility Regulation," Fifth Annual Seminar Series, Hendrix College, 1984.

"The Economics of Two-Part Rate Structures for Regulated Utilities," Midwest Economics Association Convention, 1981.

COLLEGIATE SERVICE

Director, Center for Entrepreneurial Studies, Hendrix College, 2001-Present. The Center brought Secretary of Commerce Don Evans, former Secretary of HUD Jack Kemp, and former Council of Economic Advisors Chair Dr. Glenn Hubbard to speak to the Hendrix campus. Additionally, the Center sponsored a number of Business Roundtables where local businesspeople spoke to Hendrix students. In 2004, the Center provided supervision for a Hendrix Team that was a semi-finalist in the Governor's Business Plan Competition.

Faculty Advisor, Phi Beta Lambda, the Collegiate Division of Future Business Leaders of America, 2002 –Present.

Committee on Enrollment and Financial Aid, Hendrix College, 2002-03

Chair, Committee on Curriculum, Hendrix College, 1998-2002. Responsible for development of new General Education Requirements as Hendrix College moved from a trimester calendar to a semester calendar.

Member of Search Committee for Provost for Hendrix College, 2002

Member of Faculty Committee that assisted in the writing of a $3.9 million grant to Hendrix College from the Robert & Ruby Priddy Charitable Trust, 2002

Hendrix College Alumni Association Board of Governors Awards Committee, 1999-2000

Committee on International/Intercultural Studies, Hendrix College, 1996-97

Chair, Committee on Student Life, Hendrix College, 1995-96

Committee on Student Life, Hendrix College, 1994-95

Committee on Library Resources, Hendrix College, 1993-94

Committee on Special Events, Hendrix College, 1992-93

Committee on Curriculum, Hendrix College, 1990-92

TESTIMONY OR REPORTS PRESENTED TO COMMISSIONS OR AGENCIES

Federal Energy Regulatory Commission, Docket No. ER03-583-000, et al.
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Federal Energy Regulatory Commission, Docket No. ER03-753-000
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Securities and Exchange Commission, File No. 70-9785
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Testimony concerning the merger of American Electric Power and Central and South West, May, 1999 and June, 1999.

Federal Energy Regulatory Commission, Docket No. EC99-18-000

Affidavit concerning the proposed acquisition of Pilgrim Nuclear Unit by Entergy Corporation, January, 1999.

Securities and Exchange Commission, File No. 70-9049
Affidavit concerning financial risk of diversification of Entergy Corporation, October, 1998.

"Report on the Cost of Equity of New York Power Authority," December, 1997.

State of Arkansas General Assembly
Economic Policy Analysis of Telecommunications Reform Act of 1997, January, 1997.

Securities and Exchange Commission, File No. 70-8725
Affidavit concerning financial risk of diversification of Southern Company, October, 1996 and January, 1997.

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Testimony concerning the equalization of nuclear decommissioning costs of Entergy, October, 1996.

Securities and Exchange Commission, File No. 70-8809
Affidavit concerning financial risk of diversification of Central and Southwest. May, 1996.

"Report on the Cost of Equity of New York Power Authority," January, 1996.

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"Report on the Development of Electric Utility and Railroad Comparable Samples for the Tax Division of the Arkansas Public Service Commission," February, 1995.

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Affidavit concerning the merger of Central and Southwest and El Paso Electric. April, 1994.

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Testimony concerning the merger of Central and Southwest and El Paso Electric. February, 1994.

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Testimony concerning the merger of Entergy and Gulf States Utilities. March, 1993.

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Testimony concerning franchise fee or tax on AT&T in the City of Little Rock. January, 1992.

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Testimony concerning the spin-off of a coal unit on the Entergy System. January, 1992.

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Economic and Financial Report on the Feasibility of the Proposed First Community Bank, Conway, Arkansas, May, 1991

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Testimony concerning the cost of capital of System Energy Resources, Inc. and Middle South Services. March, 1987

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Testimony concerning the rate of return and an econometric model of demand for Arkansas Electric Cooperative Corp. July, 1980.

OTHER EXPERIENCE

Discussant at 2005 American Economics Association/TPUG Session

Reviewer for *Quarterly Review of Economics and Finance, Eastern Economic Journal, Journal of Economic Surveys, Contemporary Economic Policy, Economics and Politics, Land Economics, The American Economist, Managerial and Decision Economics, International Journal of Energy Systems*, and *Journal of Economics and Business*

Blue Ribbon Panel, advice to Frueauff Foundation concerning modification of its investment objectives, 2003

Discussant at 2001 Southern Economics Association Convention

"Report on the Economic Feasibility of the White River Navigation Project," February, 2000

Member, Board of the Arkansas Policy Foundation, 1999-Present

"The Democratization of Capitalism on Wall Street," *Log Cabin Democrat*, Conway, Arkansas, June 7, 1999

Panelist on Governor's Economic Summit, Roundtable on Tax and Regulatory Policy, June 9-10, 1998, Little Rock, AR

"Taxes and Savings in Arkansas," Murphy Commission Report, May, 1998

"Feasibility Analysis of the Formation of a Local Electric Utility in Batesville and Independence County," with Mike Hughes and W.W. Elrod,II, April, 1998

Discussant at 1999 Southern Economics Association Convention

Discussant at 1996 Western Economics Association Convention

Discussant at 1994 Southern Economics Association Convention

Discussant at 1993 Southern Economics Association Convention

Participant on judges panel for selection of outstanding Arkansas businesses and executives in 1988 for *Arkansas Business*

Lecturer, Business Leaders Day, 1988, University of Arkansas, Fayetteville, Arkansas

Research Advisory Committee, National Regulatory Research Institute, 1986-1989, Deputy Chairman (1988-1989)

Subcommittee on Electricity, National Association Of Regulatory Utility Commissioners, 1987-1989

Subcommittee on Economics, National Association of Regulatory Utility Commissioners, 1979-1987

PROFESSIONAL ORGANIZATIONS

American Economics Association
Southern Economics Association

REFERENCES

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ATTACHMENT B

Transmission Pricing and ICT Benefits

July 30, 2004

ATTACHMENT B

Pricing Overview

ICT Pricing Proposal:

- Reliability investments automatically "rolled in" (Base Plan investments)
- Upgrades beyond the Base Plan treated according to the "higher of" pricing principle of native load protection

- The determination of what upgrades are incremental to the Base Plan, and therefore subject to "higher of pricing principle", will be made by the ICT
- Comparable treatment: the policy applies to all service requests, including those made by Entergy's operating companies and affiliates

“Higher of” Principle

- “[A]llowing transmission providers to charge the higher of an incremental cost rate or an embedded cost rate ensures that other transmission customers, including the Transmission Provider’s native load, will not subsidize Network Upgrades required to interconnect merchant generation.” (Order 2003A)
- “Higher of” principle protects native load by ensuring that incremental transmission revenues exceed incremental costs (revenue requirements)
- Straightforward to apply for PTP service
- Network service application not as clear
  - what is the definition of “incremental revenue”?
  - how should the “higher of” principle be applied when “incremental revenues” are zero?

Example

- 3000 MW Network Customer, 10% T load ratio share, $36 MM NITS charge
- Supply contract expiring, two choices:
  - Supplier A power cost $10 MM/year lower than B, but requires network resource transmission upgrades that cost $20 MM/year
  - Supplier B power cost $10 MM/year higher than A, but requires no transmission upgrades

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Example (cont)

- If total NITS charge is defined as “incremental revenue”, the average rate ($38MM) exceeds the incremental rate ($20MM) and Supplier A upgrades are “rolled in”
- Customer chooses Supplier A
  - Customer saves $8 million
  - But native load costs increase by $18 million
- This definition does not protect native load or give proper incentives for economic behavior

Example (cont)

- But the result is even worse if the customer pays the incremental rate ($20 MM) *instead* of the average rate ($38 MM)
- Customer chooses Supplier A and saves $26 MM/year
- Native load costs increase by $36 MM/year

The Issue

- Incremental revenue associated with new network resource qualification is generally zero
  - Always zero for resource displacement/ replacement
  - And also zero for load growth except for "above average" growth
- When incremental revenues are zero, neither the average rate nor the incremental rate provide native load protection

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Implementing the Native Load Protection Principle

- For new network resource qualification, requesting party pays the incremental rate
  - ICT determines what is "incremental"
- Requesting party gets "property rights"
  - "Portable" network resource status
  - Allowance for free PTP service on an ATC-available basis
- Load-based network service charges not affected

Is It "And Pricing"?

- Designed to be as similar as possible to other FERC-approved approaches
  - Portable network resource status
  - PTP allowance
  - Congestion hedge (for NITS service), but not FTRs
  - Determination of incremental investment made by independent entity (ICT)
- Any other approach would not provide the native load protection from the cost of network resource upgrades described in Order 2003A

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Transmission Pricing Summary

- Consistent with Order 2003A Pricing Principle -- protects native load
- Sends efficient price signals
- Full comparability between Entergy and other network customers

ICT Independence

- ICT will be independent from Entergy and all other market participants
- ICT will meet FERC independence standards for market monitors
- ICT will have a full staff, including a 24/7 desk
- Entergy cannot unilaterally terminate the ICT if a disagreement occurs; FERC approval would be required
- FERC will resolve any disputes over budgets, access to data, etc.

Benefit/Cost Overview

Benefits

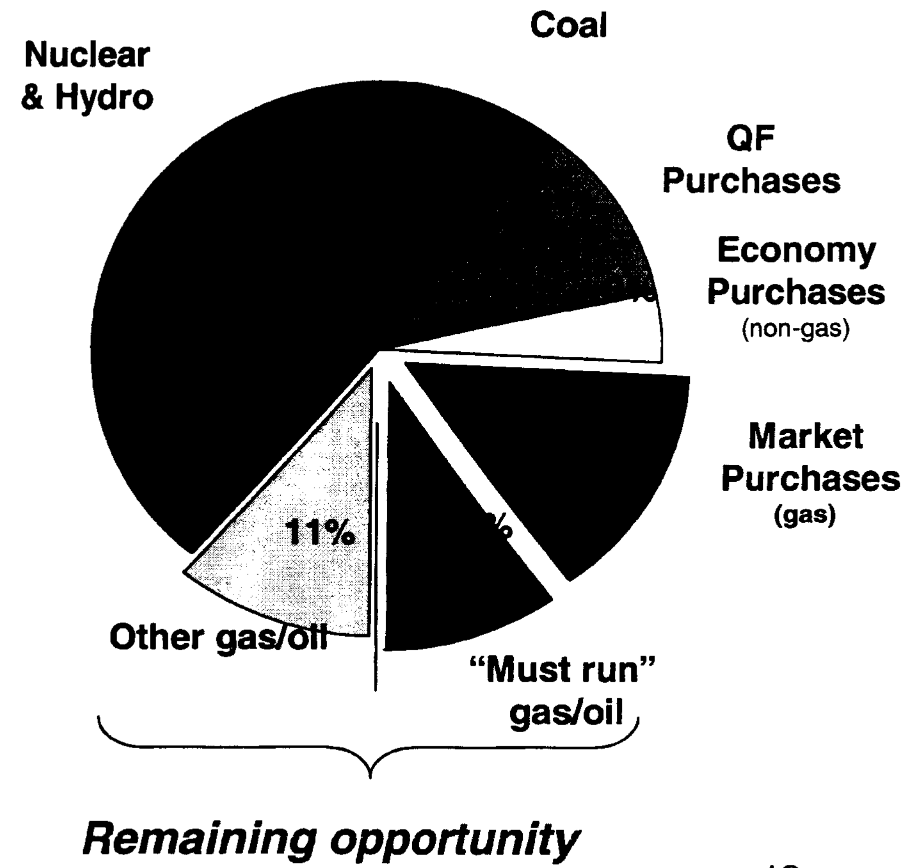
- WPP savings/additional revenues
- Reduced exposure to transmission expansion costs (native load protection)

- Costs – Incremental costs associated with the proposal
- Compared to both status quo and RTO alternatives

ENERGY COST SAVINGS (WPP)

- Current purchases account for 17% of annual energy
- The remaining opportunity is potentially significant
- While there are limits on the level of displacement, every percentage point decrease in oil/gas generation (e.g. from 20% to 19%) results in savings of approximately $30 million per year

2003 ENERGY REQUIREMENTS



Summary of Benefits and Costs

ICT Savings versus Status Quo Case

- Transmission Investment
  - $24-$35 mm/yr
  - $240-$360 mm pv
- WPP: $30 mm/yr/1%
- $15 mm annual cost

ICT Savings versus RTO Alternative

- Transmission Investment
  - $125 mm/yr
  - $1050 mm pv
- WPP: $30 mm/yr/1%
- $0 incremental cost

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ATTACHMENT C

ATTACHMENT C

THE LPSC STAFF RETIREMENT STUDY

Preliminary Draft Report for Comment

Phil Hayet, J. Kennedy & Associates, Inc.
Matt Kahal, Exeter Associates, Inc.

Submitted on Behalf of the
LPSC Staff

March 2, 2005

Statement of the Problem

- ☒Entergy System has more than 14,000 MW of old, inefficient gas/oil capacity, approximately 65% assigned to ELI/EGS.
- ☒17,000 MW of new merchant/cogeneration capacity has come on line within the last 3 to 5 years on the Entergy grid.
- ☒Entergy plans to add about 4500 MW over the next several years under its Strategic Supply Resource Plan (SSRP) to meet its capacity shortfall, but has no plans to retire any of its existing inefficient capacity.
- ☒Merchants/LSU studies estimate very large energy cost savings if Entergy would use local merchant generation to displace its own inefficient gas/oil generation.
- ☒Compounding the problem, ELI/EGS fuel adjustment charges have increased sharply as gas prices have gone up.
- ☒One way to exploit the savings opportunity is to retire old capacity and replace with market resources through a competitive process.

Staff View of the Problem

☒ELI/EGS obligated to provide reliable service at lowest reasonable costs. Hence, an obligation to explore the power plant replacement issues.

☒Studies showing very large annual savings estimates are incomplete because they do not account for:

-- capacity costs of the replacement merchant resources

-- savings already available from the short-term economy market

☒Over time, energy production from existing inefficient units should fall due to SSRP additions and planned transmission upgrades.

☒Much of the existing gas/oil generation cannot be displaced without addressing "reliability must run" requirements, but still there remains a portion that can be.

☒Reliance on the economy market (e.g., weekly procurement) is only part of the answer due to a lack of Available Transmission Capacity on Entergy's grid.

☒Whether net savings are attainable can only be determined by careful study. Answer also depends on market bids.

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The Plan of Attack – Staff Methodology

(1) Start with Entergy's current capacity expansion plan (SSRP), load forecast and data base. No retirements of existing units. SSRP includes resources in which commitments have already been made, as well as, resources that conceptually are being planned.

(2) Study goes out to 2012.

(3) Define four retirement scenarios:
-- 3,000 MW
-- 2,000 MW
-- 1,300 MW
-- One unit in Amite South

(4) In each scenario, we "retire" (i.e., shut down) a portfolio old Entergy gas units not required for local (or reliability must-run) transmission reliability and replace with "new" units (i.e., existing merchant capacity) located in proximity to retired units.

(5) We assume Entergy acquires the efficient new units on a "life of unit" (LOU) basis, and new units get network transmission rights of retired units.

The Plan of Attack – Staff Methodology (Cont'd.)

(6) Calculation of net savings, 2006-2012:

Fuel savings of new units, plus savings from avoiding O&M on retired units, minus the capital/O&M costs of the new units.

(7) Run the study for each year, for all four scenarios and for alternative new unit acquisition costs. Gas sensitivity case run as well.

(8) Study is intended to illustrate potential savings opportunities and is a "reality check" on previous assertions. It is not a planning blueprint, nor a set of retirement recommendations.

(9) Our "Plan of Attack" does not address transmission plan. That's another, although related, subject. It is possible transmission upgrades could enhance retirement economics.

(10) Study Monitoring Group – comments, input, data review

Outside Counsel – Stone, Pigman firm

Merchant rep. – Mark Rossi

LEUG rep. – Jim Dauphinais

Entergy rep. – Steve Dingle

The Economic Analysis Elements

(1) New unit capacity costs:

- -- Alternative acquisition costs assumed based on recent experience. Future RFPs will give us the "real" answers.
- -- Financial spreadsheet modeling translates acquisition costs into base rate annual revenue requirements.
- -- Key cost data provided by Entergy and participating merchant plants.

(2) Fuel or Energy Cost savings analysis:

- -- Based on Entergy's Promod computer simulation model (fuel, startup energy costs, purchase power, sales revenue, variable O&M).
- -- Total Systemwide analysis, "no retirement" Base Case versus Change Case with retirements/replacements.
- -- New units provide two sources of energy savings
  - huge efficiency advantage over retired units
  - new units also displace economy purchase (physical heat rate versus market heat rate)
- -- Biggest challenge in study was getting the Base Case right.
- -- Gas prices are a major driver.

The Economic Analysis Elements (Cont'd.)

(3) Retired units

-- New units get the transmission rights of the retired units.

-- We save fixed O&M and capital additions of retired units.

-- Sunk costs (today's net investment) for retired units are ignored. These are not avoidable costs.

-- MSS-1 effects are ignored. Not a Systemwide cost or benefit and is also a "wash" at EOC level. (Note: new units could affect MSS-1 prices.)

Getting the Base Case Modeling Right

- ☒It is crucial that the Promod Base Case realistically reflects how the System actually operates, particularly the interaction of Entergy's gas units and the economy market. Operational constraints that force old gas units to operate are also crucial.

- ☒Staff has concluded that Entergy's Promod Base Case modeling is too optimistic, resulting in the model showing the Entergy gas units running much less than we observe. This biases against finding retirement benefits (since the economy market provides those benefits with no retirements).

- ☒Too pessimistic a view of the economy market would overstate retirement savings.

- ☒Staff's Promod Base Case builds on model development work by the LPSC in the FERC PPA case.

- ☒Our crucial change from Entergy's modeling of merchant units is to employ observed market prices (i.e., heat rates) rather than assuming units bid in at physical heat rates and are paid based on an LMP pricing structure.

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Getting the Base Case Modeling Right (Cont'd.)

☒In the FERC PPA case, Staff concluded that Entergy's LMP based modeling was not consistent with the operation of its market. Problems with Entergy's modeling were that:

-economy merchant units were treated as firm, fully dispatchable resources by Entergy's that could be relied on to satisfy Entergy's load requirement and operating constraints, without appropriate compensation made to the merchants.

-economy merchant units dispatched based on unit actual heat rates and fuel costs, as opposed to merchant offers or bids.

-no capacity payments paid for the rights to operate the units in this fashion.

-merchant units paid nodal based prices that do not exist in reality. Uplift payments made in the event that merchant units did not fully recover their operating costs, which was typically the case.

-very large merchant QF units modeled like other firm, fully dispatchable merchant units, but with the total generation and costs assigned situs. No consideration of the fact that they may operate as merchant units.

Getting the Base Case Modeling Right (Cont'd.)

- ☒LPSC Staff implemented a new structure in which merchant units bid in prices and are paid as bid. Bid prices tied to a heat rate assumption times the forecasted fuel price.

- ☒Staff analyzed market price data and concluded that the following heat rate assumptions are reasonable:
  - on-peak non-summer heat rate = 8,000 Btu/kWh
  - on-peak summer heat rate = 8,500 Btu/kWh
  - off peak all year heat rate = 7,700 Btu/kWh

- ☒Staff concluded that economy merchant unit owners would <u>not</u> suffer a loss if paid anything above a 7,700 Btu/kWh heat rate, just considering variable operating costs.

- ☒Old Entergy gas fired generation was operating too little in the base case when comparing PROMOD results to historical 2002 through September 2004 results.

- ☒12 month ending September 2004 actuals compared to 2005 PROMOD showed about 8,000 GWH more actual "old gas fired generation" than shown in PROMOD.

Getting the Base Case Modeling Right (Cont'd.)

☒Differences in PROMOD compared to actual attributed to three factors:

- PROMOD not capturing all of the dispatch decisions that lead to higher old unit gas-fired generation, which can only be more fully corrected through a benchmark

- During the historical period, oil was actually cheaper than gas, and it was cheaper to operate units on oil than to purchase merchant CC gas-fired energy

- Period of 2005 and on assumes Entergy will acquire additional CC capacity which reduces the need to operate the old gas fired units

☒Staff dealt with the first issue by forcing additional old gas fired generation in the base case, which could then be displaced by acquisition units in the change cases. An increase of about 2000 GWH resulted in the base case

☒Second issue - Staff assumed that in the future, oil would not be cheaper than gas and units would burn gas throughout the study period.

Retirement Scenarios

- ☒The retirement scenarios are not "optimized" but rather judgmentally selected to meet certain criteria. Not necessarily the absolute best retirement candidates.

- ☒Units selected for retirement are not needed for transmission reliability, i.e., no RMR, Downstream of Gypsy units, etc.

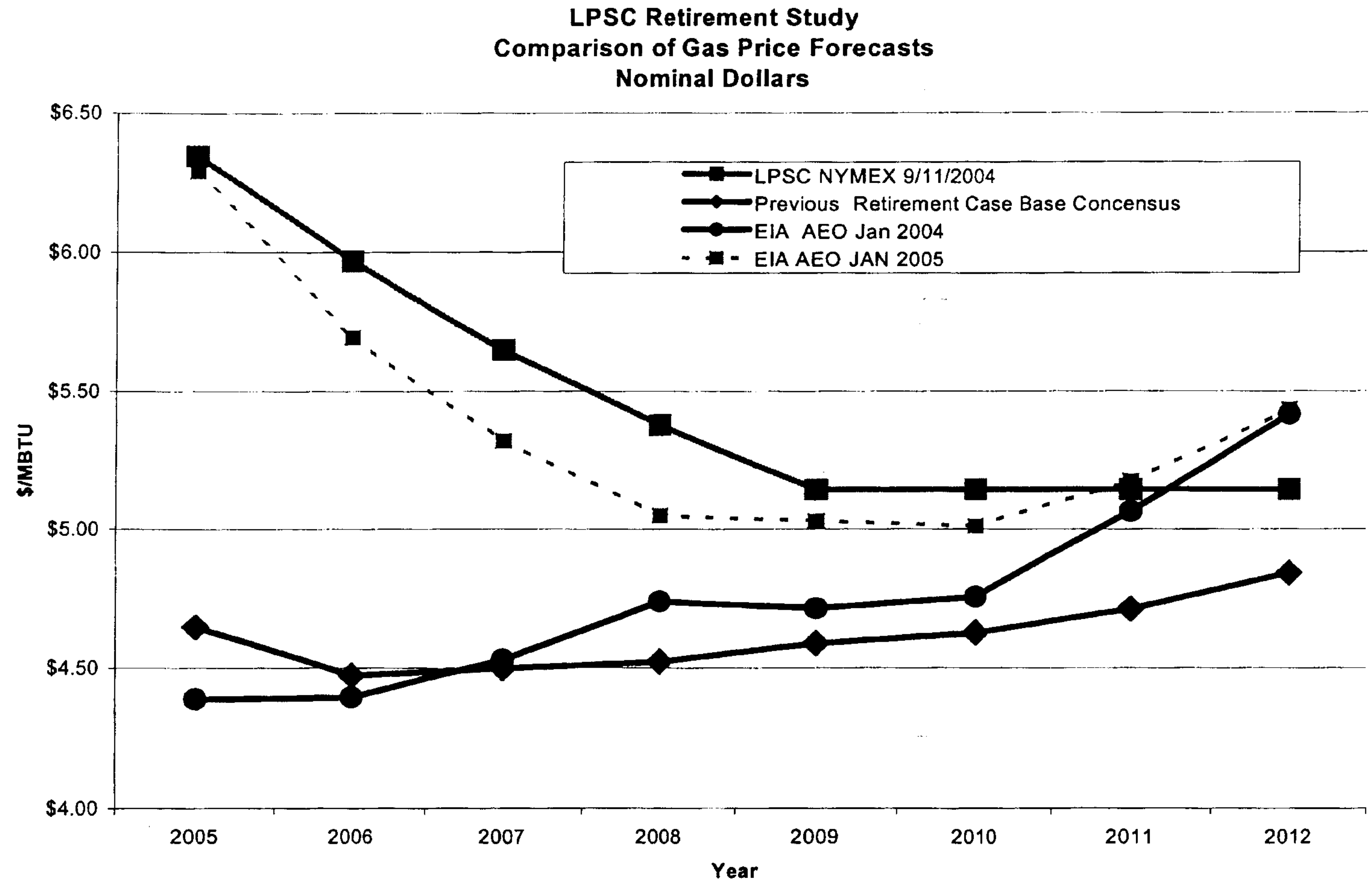
- ☒Retirement units are the extremely low-load factor, inefficient units.

- ☒An attempt was made to obtain some geographic and EOC diversity in constructing retirement/replacement portfolios. Wanted to avoid all retirement/replacements being all in one area or applicable to one EOC.

- ☒In reality, the best market bids could be the driver of the specific units retired and selected for replacement. The location of the best bids not known in advance.

- ☒Fourth scenario mitigates the Amite South/DSG problem by retiring Michoud 2 (530 MW) and replaces it with a 530 MW CCGT that is electrically equivalent.

Gas Price Forecast



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The Fixed Cost Side of the Study

- ☒Acquisition price assumptions for new units.
- ☒Translate capacity acquisitions in to base rate annualized revenue requirements.
- ☒Add in O&M cost assumptions for new units.
- ☒Net out O&M/Cap Add savings from retired units.
- ☒These base rate revenue requirements will be compared with the Promod-derived fuel savings.

Resource Acquisition Costs

-- Five acquisition price assumptions, four reflecting huge discounts to CCGT construction costs. Amite South case based on new construction costs.

-- Large uncertainties over what merchant LOU (or long term) offers will be over next 3 years.

-- Market for asset acquisitions is illiquid, time consuming, regulatory approvals uncertain.

-- Perryville CCGT probably equivalent to $250 to $300 per kW acquisition cost. Is this "market?"

-- Relevant acquisition cost would be the market offer <u>after</u> SSRP objective is met. Supply curve slopes upward.

-- Staff scenarios are meaningful but hypothetical. Only an RFP will reveal actual acquisition cost opportunities.

Base Rate Annual Revenue Requirements

-- 30-year levelized values based on ownership/rate base (a proxy for a LOU PPA) for a merchant CCGT plant.

-- Pre-Tax ROR = 11.5% + 1.0% for property taxes/insurance (1% x original cost)

-- Discount Rate = 7.0%

-- Fixed O&M, $15 per kW-year

-- O&M savings from retired units, $6 to $12 per kW-year

-- Variable O&M included in Promod results, not base rates

-- No transmission upgrades, transaction costs, or explicit cap adds included in replacement capacity costs.

-- Staff regards its revenue requirement estimates as aggressive, given the acquisition costs.

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Fixed O&M Savings

-- Entergy study for Fall 2004 RFP estimates savings in ERS context of about $6 per kW-year.

-- Entergy omits cap add savings (since with ERS cap adds are only deferred not saved).

-- Entergy estimate of $6 per kW-year confirmed by recent TXU study in ERCOT, for 2,600 MW of gas unit retirements.

-- FERC Form 1 data support higher number, about $12 per kW year, but those data are station level, not unit level, and include common costs not avoidable.

-- Major (expensive) component failure (at a unit not needed for reliability) might provide a retirement savings opportunity.

-- Entergy Fall 2004 RFP analysis is a good first step, but further analysis is needed.

-- Extended Reserve Shutdown (ERS) versus retirement. Has cost savings implications.

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Levelized Annual Base Revenue Requirements (million $)

Acquisition Scenario	kW-Mo.	2,950 MW	2,072 MW	1,295 MW	530 MW
Very Low	$2.78	$ 98.20	$ 68.92	$43.18	-
Low	$3.29	$116.14	$ 81.51	$51.05	-
Medium	$3.79	$134.07	$ 94.11	$58.93	-
High	$4.30	$152.00	$106.70	$66.80	-
Amite South	$ 6.83	-	-	-	$43.44

*If O&M high side savings is used, additional savings are $18 million for 3,000 MW case, $12 million for 2,000 MW case and $8 million for 1,295 MW case. In Amite South additional savings would be $3 million.

The Promod Energy Cost Savings

- ☒ Annual results 2006-2012
- ☒ Calculated as Base Case versus Change Case and includes fuel costs, purchase power costs and variable non-fuel O&M.
- ☒ Accounts for margins Entergy receives from off-system sales using its regulated generation. Entergy's share of those sales margins increases when it acquires more units from the market.
- ☒ Results are presented for total System, ELI and EGS-Louisiana for the four retirement scenarios.
- ☒ Two Sensitivity Cases conducted at request of Working Group
  - -- High gas price case (20% over base gas price forecast)
  - -- SSRP only partially completed

SYSTEMWIDE ENERGY COST SAVINGS, 2006 - 2012 (MILLIONS OF $)

Year	3,000 MW	2,000 MW	1,300 MW	AMITE SOUTH	GAS PRICE SENSITIVITY*
2006	$115.11	$68.49	$70.88	$0.00	$88.59
2007	$113.45	$68.91	$72.89	$0.00	$90.60
2008	$92.12	$56.13	$61.50	$50.77	$77.43
2009	$99.98	$59.48	$56.82	$57.17	$71.33
2010	$100.62	$66.14	$63.46	$67.12	$77.58
2011	$61.86	$32.03	$38.76	$46.98	$52.82
2012	$75.41	$44.78	$50.11	$50.91	$67.84
Average	$94.08	$56.56	$59.20	$54.59	$75.17

* Based on a 20% increase in the Base Case gas price forecast. Results are for the 1,300 MW case.

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ELI ENERGY COST SAVINGS, 2006 - 2012
(MILLIONS OF $)

Year	3,000 MW	2,000 MW	1,300 MW	AMITE SOUTH	GAS PRICE SENSITIVITY*
2006	$88.55	$33.63	$30.51	$0.00	$37.56
2007	$76.17	$28.06	$26.78	$0.00	$33.29
2008	$68.42	$22.10	$25.25	$17.18	$32.17
2009	$77.97	$37.74	$29.50	$17.45	$36.20
2010	$79.47	$40.75	$28.35	$15.12	$34.77
2011	$50.97	$9.53	$11.78	$13.01	$15.55
2012	$60.05	$19.66	$23.44	$20.41	$29.39
Average	$71.66	$27.35	$25.08	$16.63	$31.28

* Based on a 20% increase in the Base Case gas price forecast. Results are for the 1,300 MW case.

EGSI-LA ENERGY COST SAVINGS, 2006 - 2012
(MILLIONS OF $)

Year	3,000 MW	2,000 MW	1,300 MW	AMITE SOUTH	GAS PRICE SENSITIVITY*
2006	$10.43	$4.78	$5.00	$0.00	$6.68
2007	$14.09	$8.23	$6.54	$0.00	$8.89
2008	$10.79	$6.20	$5.37	$3.87	$7.02
2009	$10.29	$6.80	$5.48	$4.25	$7.61
2010	$10.19	$10.42	$9.00	$5.22	$11.23
2011	$9.86	$10.95	$7.31	$2.82	$10.00
2012	$10.10	$10.14	$6.87	$2.93	$9.53
Average	$10.82	$8.22	$6.51	$3.82	$8.71

* Based on a 20% increase in the Base Case gas price forecast.
Results are for the 1,300 MW case.

SYSTEMWIDE NET SAVINGS/(COSTS) FOR RETIREMENT/REPLACEMENT SCENARIOS (average 2006-2012, millions $ per year)

ACQUISITION COST	3,000 MW	2,000 MW	1,300 MW	AMITE SOUTH	GAS PRICE SENSITIVITY*
EXTRA LOW	($4.12)	($12.36)	$16.02		$31.99
LOW	($22.06)	($24.95)	$8.15		$24.12
MEDIUM	($39.99)	($37.54)	$0.28		$16.25
HIGH	($57.92)	($50.14)	($7.60)	$11.15	$8.37

* Based on a 20% increase in the Base Case gas price forecast.
Results are for the 1,300 MW case.

ELI NET SAVINGS/(COSTS) FOR RETIREMENT/REPLACEMENT SCENARIOS
(average 2006-2012, millions $ per year)

ACQUISITION COST	3,000 MW	2,000 MW	1,300 MW	AMITE SOUTH	GAS PRICE SENSITIVITY*
EXTRA LOW	$44.10	$17.52	$18.85		$25.04
LOW	$39.07	$15.73	$17.72		$23.91
MEDIUM	$34.05	$13.94	$16.58		$22.77
HIGH	$29.02	$12.14	$15.44	$16.63	$21.63

* Based on a 20% increase in the Base Case gas price forecast. Results are for the 1,300 MW case.

EGSI-LA NET SAVINGS/(COSTS) FOR RETIREMENT/REPLACEMENT SCENARIOS
(average 2006-2012, millions $ per year)

ACQUISITION COST	3,000 MW	2,000 MW	1,300 MW	AMITE SOUTH	GAS PRICE SENSITIVITY*
EXTRA LOW	($7.36)	($13.36)	$0.00		($1.61)
LOW	($10.69)	($17.31)	($5.69)		($3.49)
MEDIUM	($14.02)	($21.25)	($7.57)		($5.37)
HIGH	($17.34)	($25.20)	($9.45)	$3.82	($7.25)

* Based on a 20% increase in the Base Case gas price forecast.
Results are for the 1,300 MW case.

THE AMITE SOUTH CASE
NET BENEFITS, 2006 - 2012
(MILLIONS OF $)

Year	SYSTEM	ELI	EGSI-LA
2006	$0.00	$0.00	$0.00
2007	$0.00	$0.00	$0.00
2008	$7.33	$17.18	$3.87
2009	$13.73	$17.45	$4.25
2010	$23.68	$15.12	$5.22
2011	$3.55	$13.01	$2.82
2012	$7.48	$20.41	$2.93
Average	$11.15	$16.63	$3.82

Environmental Issues

☒No environmental compliance costs savings are reflected in study because none has been identified as of this writing. Could change with new environmental legislation.

☒No material issues concerning SO_2 or mercury.

☒Retirement/replacement will provide savings in NO_X emissions (an ozone precursor). In the 1,300 MW scenario we estimate an annual average reduction of 1,512 tons per year.

☒Retirement/replacement will provide savings in gas consumption and CO_2 emissions. The 1,300 MW case provides a savings of about 7.2 million MMBtu gas usage and a reduction of CO_2 emissions of about 425,000 tons per year.

☒Our environmental analysis is based only on reductions in generation from Entergy gas/oil units versus replaced by CCGT units that are assumed to be 30 to 40 percent more fuel efficient with lower NO_X emissions rates. Other effects, such as charges in coal generation, are very minor and are ignored.

Other Ways to Mitigate System Energy Costs

- ☒Many market purchase tools available (hourly market, weekly procurement, monthly procurement, limited-term MUCCO/MUCPA).
- ☒Entergy gas/oil annual generation during the past two years at about 22 million mWh, or 18 percent of total system power supply. Much of it associated with RMR/load pocket constraints and cannot be displaced given current transmission system.
- ☒Entergy gas/oil generation likely to decline over time with planned transmission upgrades and SSRP. PROMOD modeling demonstrates that there should be a decline over time, to a level required to only satisfy local area transmission reliability constraints, should no other cheaper resource alternatives exist in those areas.
- ☒Transmission constraints a major factor in limiting economy energy purchases. Addressed by planned upgrades, ICT/WPP process, FERC investigation of AFC.
- ☒Current WPP provides about 600 MW participation but 80 to 90 percent of bids rejected. Hope is that ICT will provide improvement to weekly procurement.

Preliminary Findings and Conclusions

- ☒ Entergy has major challenges on its plate in moving ahead with its SSRP and improving its economy market procurement process (going from WPP to ICT).

- Previous studies obtained larger benefits than our study because we are reflecting (a) the capacity costs of replacement units; (b) must run constraints on existing Entergy gas units; (b) the gas displacement effects associated with Entergy's planned SSRP; and (d) opportunities for low cost purchases in the economy market.

- ☒ Our modeling suggests that if Entergy sticks to its plan for future resource acquisitions, economy market purchases, and planned transmission upgrades, there will be substantial gas-fired energy reductions, although some of the retirement cases lead to further gas reductions.

- ☒ The 1,300 MW case suggests potential savings, depending on market bids. Hence, Entergy's planning process should consider going beyond the SSRP.

- ☒ Entergy's Reserve Capacity Product in its pending RFP really does not address central theme problem – too much generation from high cost gas/oil units.

- ☒ Transmission access clearly is a vital issue but not addressed in this study. Long-term capacity acquisitions have the potential to overcome the transmission problem to some degree.

Preliminary Findings and Conclusions

- ☒A new CCGT in Downstream of Gypsy has the potential to provide savings. More study needed, including whether any other units in the DSG area would no longer be needed for voltage support once additional capacity is added to the area.
- ☒It would be useful for Entergy to further evaluate O&M/Cap Add savings associated with shutdown of (non RMR) old oil/gas units.
- ☒Over time, prices for both long-term and short-term purchase power products are likely to escalate. This is not captured in our study.